Northeast CHP Initiative
c/o Policy Subcommittee Chair
Sean Casten
Turbosteam Corporation
161 Industrial Blvd.
Turners Falls, MA 01376

July 31, 2002

Mary Cottrell
Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

Dear Ms. Cottrell,

We are submitting this letter in response to DTE 02-38, "Order Opening Investigation Into Distributed Generation", as representatives of the Northeast CHP Initiative (NECHPI). We applaud you for taking this effort to better understand the issues associated with DG – and particularly as they affect the distribution companies. It is this interface that will ultimately determine the success of DG adoption in Massachusetts, and one which has, to date received far too little attention.

The NECHPI is a volunteer group organized by (but independent of) the U.S. Department of Energy, as a direct result of their Federal-level efforts to accelerate the adoption of combined heat and power (CHP) in the U.S. Our mission is to:

> *"Lead the region in encouraging the use and implementation of CHP technologies; to drive CHP roadmap action items for the Northeast Region in support of DOE's and EPA's goal of doubling CHP use by 2010; and to provide a central point for coordination and communications among the various stakeholder organizations in the region, including federal agencies, state agencies, utilities, project developers, equipment manufacturers, CHP users, universities, research institutions and public interest groups".*

Central to our organization is the recognition that energy efficiency – in any form – delivers a multiple "wins" to society, in the form of reduced energy costs, reduced emissions of every major pollutant, reduced risk of global warming and enhanced energy security. It is our belief that CHP is perhaps the most universally applicable energy efficiency technology known, with the potential to be deployed throughout the industrial, commercial and institutional sectors. Furthermore, because CHP design must take into account local thermal and electric needs:

- As compared to central, merchant power plants, it is necessarily small (50 kW – 100 MW), sized to local, rather than regional thermal and electric loads.
- Its successful deployment implies a paradigm shift from a system based exclusively on central power generation to a hybrid system that also includes smaller interconnected generators.
- It creates additional benefits in the form of system reliability and resilience to terrorist threats – for the simple reason that a system of many small generators is less vulnerable than one based on a few large generators.

In short, Combined Heat and Power (CHP) is Distributed Generation (DG) – and as such, it faces the same opportunities and barriers to installation that all DG technologies will face. However, unlike most DG technologies, it has a long record of field proven service, dating back to 1886 when Thomas Edison built the world's first power plant – a CHP plant in New York City. While none of our individual memories go back that long, we hope that our perspective as an industry will prove valuable to you as you work to develop an understanding of the barriers to the interconnection of DG in Massachusetts.

On a national level, you should be aware that both the Department of Energy (DOE) and the Environmental Protection Agency (EPA) are actively supporting the growth of CHP as a means to improve energy reliability, efficiency and economic competitiveness. In May 2001, President Bush cited CHP in his National Energy Policy Address in St. Paul, MN:

> *"I had an early look at the future this morning right here in St Paul. I toured a plant that harnesses the best of new technology to produce energy that is cleaner, and more efficient, and more affordable. The plant boils enough water to heat 146 major office buildings in downtown St. Paul. Not a bit of energy is wasted, not even the waste. The excess heat generated as the water boils is captured and used to create steam which generates still more electricity to power pumps and to deliver heat. The plant is a model of energy efficiency. It is also a model of energy diversity. It uses conventional fuels like oil, natural gas and coal, and renewable fuels like wood chips. And the plant is a model of affordability. While other energy prices rise, District Energy has not raised its heating and cooling rates in four years."*

The reason for this broad support is quite obvious: CHP represents the most cost-effective form of power generation ever invented. However, with this great advantage comes a great obligation on the part of the DTE: since the most cost effective DG is CHP, a failure to sufficiently support DG is tantamount to a failure to support CHP. And the stakes are huge. **We estimate that full implementation of CHP in the U.S. – using proven technologies – would save the country approximately $100 billion per year, and reduce CO_2 emissions by 1 billion tons per year.** We know of no other CO_2-control strategy that presents such a compelling win-win – but also know of no other CO_2-control strategy that faces such formidable barriers to implementation.

We hope that you will take this missed opportunity into account as you review our comments herein.

Response to Questions

1(a): Do current standards and procedures act as barriers to the installation of distributed generation?

Yes, without question, but primarily at a political (rather than technical) level. Reasonable technical requirements are required for the installation of distributed generation, and when such requirements are put in place, DG generally proceeds. However, these reasonable requirements are far too often burdened by financial and/or political objections to DG that go far beyond the basic technical requirements, but often present themselves as technical objections. For example:

- U. Mass Amherst has an electricity contract which stipulates that their rates will rise if they install any more cogeneration capacity than they already have in place. To put this another way, UMass will be penalized if they take an action that will save them money and reduce their fuel consumption (and combustion) for power generation.
- A 50 kW system installed at the Suffolk County Prison in Boston was prevented from commissioning for a full year until Boston Edison had completed a technically unnecessary interconnection feasibility study. During that delay, the prison paid more than it needed to for electricity, and needlessly degraded the quality of our environment by relying on older, dirtier power generators to serve local loads.

This is the tip of the iceberg, but variants of this theme occur far too often. Political and financial concerns drive the utility, who presents them to their customer as technical issues. The customer – who is not typically in the business of generating electric power – often lacks the expertise or inclination to argue, and projects are either postponed or completely blocked. Meanwhile, regulators like DTE are led to the conclusion that these are technical issues, which demand technical solutions – and thus devote the wrong resources to the right problem.

So why do we wind up in this situation? Not because of technical issues associated with interconnection, but rather because utilities operate within a regulatory environment which fails to reward them for investments in energy efficiency, or for any installations of customer-sited generation. This is especially true in Massachusetts, where the distribution utility is legally barred from owning generation assets – meaning that their principal source of revenue is the kWh that they sell through their wires. Any customer who is considering the installation of a distributed generator is therefore considering an action that depresses the profitability of the distribution utility. Like any company, the utility will act to protect its revenue stream. However, unlike any other company, the utility is allowed to take anti-competitive actions to do so.

The unfortunate irony is that in many cases, it is less capital intensive to install DG than it is to upgrade the capacity on the T&D system to deliver an equivalent number of kW at the point of use – but the ban on DisCo ownership of DG assets means that the DisCo cannot realize this value. Furthermore, the value of displaced T&D investment is growing by the day. Over the past decade, restructuring-induced uncertainty has created an environment in which utility investment in distribution assets has not kept pace with urban load demand growth. Grid reliability has surfaced as a critical economic issue in cities like Boston, New York and Chicago. (In Chicago, the City Energy Office has gone so far as to form a Distributed Generation Plan to enhance electricity reliability and energy efficiency rather than rely solely on the local electric utility to perform maintenance and upgrades in the interests of the local economy.)

So are there technical barriers to DG? Absolutely. But these are the proximate barriers – the smoke, if you will. The ultimate barriers are the underlying features of our utility regulatory system that affect the behavior of DisCos with respect to DG. If your goal is to get rid of the smoke, you must first put out the fire. At a high level, the fire – the ultimate barriers to DG – are as follows:

- The ban on DisCo's right to own generation assets
- Our failure to prosecute utilities who engage in anti-competitive practices.
- Cost-plus pricing models that implicitly penalize electric utilities who invest in energy efficiency and/or capital cost minimization.
- The presence of a regulatory structure that fails to question the "central paradigm" – namely, the viewpoint that the optimal way to make power is in large central plants connected by miles of wires. Every CHP installation in the U.S. (of which there are in excess of 22,000 MW of electric capacity) saves money for its users and improves the environment – and yet our current regulatory structure treats them primarily as costs to be borne or avoided by the local utility.

1(b): Should the state adopt uniform interconnection standards?

Yes, but not without first learning the lessons from those we have already installed. The IEEE efforts at developing a standard interconnect rule are well-intentioned, but ultimately suffer from trying to fit too many variables into a single standard. The technical ramifications of interconnection are enormously dependent on the way in which a device is interconnected. Consider:

- Generators that are designed to export power to the grid have the potential to create issues associated with power factor degradation, harmonics and islanding on the grid – but generators designed exclusively for "behind the fence" generation have little to no impact on these features of grid power.
- Generators with DC/AC inverters and power electronics have the potential to create a host of issues with harmonics and power factor that are unique to their

design – but are completely absent in generators with more conventional induction/synchronous AC generator designs.
- Synchronous generators <u>have the potential</u> to present islanding issues that are non-existent in induction generators.

Taken together, a truly uniform interconnect standard very quickly becomes a general document that is inappropriate for the specifics on any individual generator. This is not simply a matter of too much technical rigor – DG projects are by definition small. Detailed interconnection requirements that burden projects with unnecessary transaction costs may therefore serve to inhibit the very projects that they are seeking to encourage.

We would therefore urge the state to develop a *series* of standard interconnection documents, classified by generator type and interconnection mode (behind the fence-exclusively or with power-export functionality). This series of standards would outline the interconnection requirements for generators depending upon a few key characteristics of their design, and are listed below from the most to least complex:

1) At the most complex level, a standard for any generator designed to export some or all of the electricity it produces to the grid.
2) At a lower level of complexity, a standard for any generator that is not designed to export power to the grid, but contains power electronics (and therefore has the potential to inject harmonics into the grid and/or impact the grid power factor).
3) At a still lower level of complexity, a standard for any generator that is not designed to export power to the grid, but contains an A/C synchronous generator (and therefore requires a higher level of islanding-protection than an induction generator).
4) At the lowest level of complexity, a standard for any generator that is not designed to export power to the grid and relies exclusively on induction generators to generate power. To a large degree, the impact of such generators on the electric power grid is indistinguishable from many electric motors – and should be regulated accordingly.

This formulation would ensure that a generator meets all necessary technical requirements, but also would minimize the interconnection requirements of any individual generator. Note also that this level of complexity is independent of the power output of the generator – an arbitrary criteria that was used in NY State's interconnect requirements, but ultimately has no technical significance.

2: <u>Do standby tariffs act as a barrier to DG?</u>

Yes, in some cases. There are lots of different rate structures, and standby tariffs certainly aren't present in all of them. As an organization whose success is ultimately contingent on the installation of many non-utility generators, we obviously have a vested interest in eliminating and/or minimizing standby tariffs. At the same time, we do appreciate the reality that utility costs often scale with peak kW delivered, so there is a clear logic to standby tariffs for those users who wish to continue to use the grid as a backup power provider. However, much like the technical requirements to generation, these financial requirements are all too often established for anti-competitive reasons, rather than legitimate financial return for service provided. As evidence, we have commonly found that the standby tariff will be increased only at the moment that a customer considers the installation of on-site power generation. When this happens, it is very difficult to argue that it has been done to ensure fair cost-recovery – it is simply done to discourage a competitive source of kWh from coming on line. (Our strong suspicion is that some utilities have established these tariffs to proactively discourage DG in their service territory as well, which makes it harder to argue that the tariff was done to block a particular installation.)

A more subtle – but critically important – point is to recognize that standby tariffs are essentially an insurance premium, and can be assessed with the identical actuarial math. A utility rate structure that includes a standby charge is implicitly assuming that the outage on a generator will correspond exactly to the hour during which the facility is consuming its peak electric power load. Statistically, this simply isn't true. A generator with a 95% reliability factor has a 5% chance of being down during any hour of the year, without consideration of the facility electric load during that hour. If the facility's peak consumption which is used in the calculation of a standby charge occurs only during 30% of the year, this means that there is a 5% x 30% = 1.5% chance that these two unlikely events will occur at the same time. An appropriate standby charge should – at the very least – factor in these probabilities, rather than calculating their charges based on the costs to provide 100% backup capacity.

Finally, any discussion of "appropriate" standby tariffs must face up to an uncomfortable reality: the net impact of a facility that elects to generate 10% of its power needs internally is identical to the impact of a facility that is facing a slowdown in business and must reduce their plant activities by 10%. Is it "appropriate" to only charge standby tariffs to those who are financially able to pay them? What if the only way a facility can stay profitable is to install on-site generation to reduce their electric loads and recapture "waste" heat for their processes? These are uncomfortable issues with no easy answers – but that doesn't make them any less relevant.

Given this tendency of standby tariffs to obscure real financial/technical issues with the artificial political/financial concerns of a monopoly utility, we believe that "appropriate" standby tariffs will only be determined in a market-driven structure. We suggest the following:

1) Remove the ban on private wires. At present, if a facility has the capacity to generate electricity at a cost that is less than their retail electric rate, they will have an incentive to do so – but only so long as they are generating as much or less than their "behind the fence" power needs. Meanwhile, their neighbors would happily buy their excess power from them – but are prevented from doing

so by a legal structure that deems the construction of private wires to be a felony offense. (When one considers the fact that this is almost inevitably blocking high-efficiency power generation – which is the only way to make cheap electric power – it becomes evident that these laws are directly responsible for increased emissions and reduced grid reliability.) Removing this ban would inject competition into the "last mile" of distribution service, and hence force DisCos to reduce their standby tariffs down to a fair level – the level at which it is cheaper for a customer to use their wire than it is to install their own.

2) Mandate that DisCo's be required to purchase power from any of their customers at a price set at their retail rate, less their profit. Electricity has a locational value, but many of the laws that are in place to encourage DG (e.g., PURPA) assume that the value of electricity is set at the central power plant, at wholesale rates. The truth is that wires are capital-intensive – and the high prices of electricity in New England reflect both a high cost of generation *and* a high cost of distribution. Since every PUC sets utility profits through their rate-setting arms, it is a simple calculation to back out the value of electricity to the end user (the retail rate) and to the utility (retail rate less their profit) at the point of use. Again, this injection of competition will force honesty into rate structures.[1]

3: <u>Discuss the role of distributed generation with respect to the provision of reliable, least-cost distribution service.</u>

This is an interesting question, but ultimately the wrong question. Should our goal as a state be to minimize the cost of *distributed* electricity, or to minimize the cost of *consumed* electricity? We would suggest it is the latter – after all, the impact of energy costs on Massachusetts citizens and businesses are a function of the amount paid for energy, not who the money is paid to. With the perspective on this change thus modified, one must ask the question: "if I can generate electricity on-site at a lower cost than I am currently paying, should I be prevented from doing so?" So long as there are no undue impacts on the environment or grid reliability, the answer to this question should be a resounding "no" – but we must then face up to the fact that under current regulations, the installation of these generators runs exactly counter to the best financial interests of the DisCo.

This is not to suggest that distribution companies will not have a role to play in the adoption of DG. The grid is not going to go away, and we will always have load pockets that are underserved. The DisCo, more than any other market participant is best positioned to use DG to address these issues. Indeed, the dominant value realized by many DG installations is in the avoided marginal costs of transmission and distribution.

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[1] To take a simple example that keeps everything on a c/kWh basis, suppose that a utility sells power for 10 cents/kWh, and has their profits set at 15%. It is then obvious that the cost of providing a kWh at the "end of the wire" is 8.5 cents/kWh. (10 x 85%) Any customer who can cost-effectively generate power for less than 8.5 cents ought to be able to profitably resell this electricity to the utility – and the utility ought to have a vested interest in buying it, since it can resell it at a greater profit than it's other kWh… provided that the information provided to the PUC was accurate.

A recent analysis by Arthur D. Little showed that the average U.S. T&D upgrade costs $1,260 per kW of electricity delivered. Like all averages, this number belies a large spread, from just a few hundred $/kW in the southwest to over $10,000/kW in Manhattan. Nonetheless, the implication of this number is clear – any distributed generator that is installed at the "end of the wire" creates substantial value to the DisCo in the form of avoided T&D costs. However, this then begs the question: can the DisCo realize these benefits? Not if they are banned from owning generation assets. And not if they are burdened by cost-plus pricing regimes that effectively serve to penalize the utility for saving money.

However, it is important to realize that this "grid support" function is just one use of DG. To presume that all DG should serve *primarily* to reduce the cost of distributed electricity is to remain stuck in the central-power paradigm. This paradigm is no longer appropriate, for the simple reason that the single most cost-effective way to generate power that anyone has ever invented is in a combined-heat and power unit that recovers the waste heat from the power generator. Central power plants and/or generators installed at the substation level to provide load management simply aren't amenable to CHP since they are sited so far away from thermal users. Does this mean that CHP is a bad idea? Absolutely not – but it does mean that the DisCo and GenCo business models are not likely to realize its value. End-users, on the other hand have enormous opportunities to save money by installing CHP products – even if doing so places them at odds with a DisCo, who (under current regulations) will see the installation of that device as a competitive threat.

To summarize: DG has a critically important role to play in the provision of least-cost distributed power, largely by virtue of the savings that accrue from avoided T&D expenses. However, we believe that DG's more valuable role will be to minimize the cost of *consumed* electricity – provided that regulatory structures recognize that such installations may often run counter to the best interests of the distribution utility.

4: <u>What other issues are appropriate for consideration as part of the Department's investigation of distributed generation?</u>

As implied by the above, we believe that the central barriers to DG have to do with the role of the distribution company – and in particular with the regulatory agency's willingness to alter "the rules of the game" such that distribution companies are allowed to profit from DG installations. At the same time, however, it is critical to recognize that there is a large fraction of end-user owned DG that is probably always going to represent a competitive threat to the DisCo, for the simple reason that it will be a competitive source of kWh. It is precisely because of this competitive threat that the DisCos will argue that DG shouldn't be installed. And it is precisely the role of the DTE to ensure that the benefits of DG are realized despite these objections. Your central challenge will be to separate the legitimate DisCo objections from their fear of competition – and you can be assured that all will take the same form: the need for standby charges, guarantees of cost-recovery, rights assured under “obligation to serve” provisions, etc.

As a result, if your goal is to encourage the adoption of DG in the state, you must also be willing to take on a host of much larger questions, including but not limited to:

1) Are 1920’s-era monopoly rights still an appropriate model for the nation’s electric system?
2) Is the central paradigm still an appropriate model for the nation’s electric system?
3) How can cost-plus utility pricing structures be reconfigured to provide utilities with incentives to invest in energy efficiency?
4) How can the separation of DisCos and GenCos in Massachusetts be reconfigured to allow DisCos to see DG as a financially viable load management strategy, without jeopardizing the progress already made towards reducing the barriers imposed by a vertically integrated electricity monopoly?
5) Customer-sited combined heat and power is a compelling win/win: customers save enough money to justify the capital expense, and society benefits in the form of reduced emissions, reduced fuel consumption, enhanced grid reliability and improved national security… and yet the vast majority of the potential applications are never installed. How can we modify the existing regulatory model to reward individuals who chose to “do well by doing good”?

The reliability benefits inherent in an interconnected electric system mean that we will always have an electric grid, and the high capital and maintenance costs of that grid mean that we will always need to maintain some degree of regulatory oversight of the system; we don’t intend these comments to be taken as an argument for a complete laissez-faire approach to utility regulation. However, we would like to point out that the same argument holds for the nation’s highways – and yet we still provide people with the freedom to choose competitive forms of transportation.

We thus believe that the answer to all of the above issues is to inject competition into the entire electricity system all the way down to the “last mile”. Indeed, “the last mile” is the most important place for deregulation, for the simple reason that so long as this portion of distribution retains a monopoly license, every potential DG installation will face a challenge from a monopolistic, well-funded competitor – and very few will be installed.

Inject competition. Remove the ban on “private wires”. Prosecute DisCos who engage in anti-competitive business practices – especially when those practices block the installation of more efficient generation technologies. But also provide a reward for those DisCos who compete fairly. Uncap their profits, and allow them to keep any savings they can engender through energy efficiency investments.

An Offer from Northeast CHP Initiative

The comments outlined herein are distilled from a document that we are currently in the midst of producing. This document, when complete will take the form of a white paper summarizing the policy recommendations that we as a group believe would best serve to encourage the adoption of CHP in the Northeast. We believe that this white paper – and the thought that has gone into it – would be an extremely valuable contribution to the request contained in DTE 02-38. The policy recommendations made in this document cover a broad swath of areas, including:

- Criteria pollutant policies
- CO_2 emissions policies
- Interconnection regulations
- DisCo regulation policies
- Demand response
- An estimate of the national benefits that could be realized by CHP adoption

Clearly, there is a broad overlap. Unfortunately, this paper has not yet been completed, and will not be ready for external dissemination until all of our members have had an opportunity to review and comment – which we do not expect to have occurred until September, 2002 at the earliest. Nonetheless, given this overlap, we would like to propose that we arrange a meeting with representatives from our group and the DTE. If this is of interest, please contact the Chair of our Policy Subcommittee, Sean Casten (scasten@turbosteam.com) or our Acting Coordinator, Scott Hutchins (scott.hutchins@ee.doe.gov).

In the meantime, we hope you find these comments useful.

Signed,

Sean Casten
Chief Executive Officer
Turbosteam Corporation
Policy Chair, NECHPI

Scott Hutchins
Acting Coordinator, NECHPI

Lawrence Ambs
Center for Energy Efficiency
and Renewable Energy
University of Massachusetts

Beka Kosanovic
Center for Energy Efficiency
and Renewable Energy
University of Massachusetts

Theodore Bronson
Associate Director
Gas Technology Institute

Charles Berry
Gas Technology Institute

Suzanne Watson
Northeast Midwest Institute

Cameron Carey
Sustainable Energy Solutions

Rick Daniels
Former Vice President
Advanced Energy Systems, Inc.

Robert P. Whitney
Senior Vice President
Trigen Energy Corporation

Robert Thornton
President
International District Energy Association

Bruce Hedman
Energy Nexus Group

Frank Wolak
NORESCO

Joan B. Saxe
Director
Maine Energy & Environment Center

John Schnebly
Founding Chairman
Northeast Sustainable Energy Association

Michael Smalec
Member, NECHPI

John Moskal
New England Energy Team
U.S. EPA Region 1

Mark Spurr
Vice President
FVB Energy, Inc.